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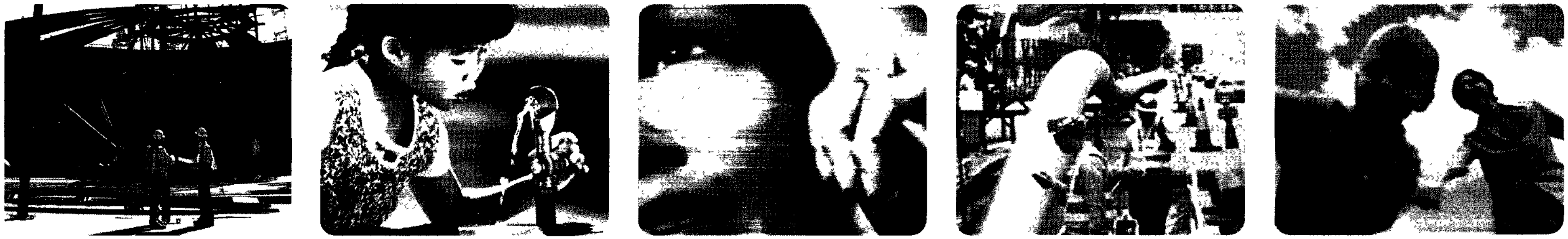

Intermountain Power Project (IPP) Greenhouse Gas (GHG) Reduction Feasibility Study

Presentation of Results

Las Vegas, NV

April 10, 2008

IP12_002420

Introductions

IP12_002421

Today's Presenters

- Bob Slettehaugh – Project Manager/CO_2 Capture
- Andy Byers – Regulatory Issues
- Matt Wood – Plant Improvements
- Matt Hunsaker – Renewable Energy

Today's Agenda

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Presentation Agenda

- General Overview of Black & Veatch (B&V)
- Key Take-aways
- Project Background
- GHG Emissions Trading Programs (Task 5)
- Efficiency Improvements (Task 1)
- Lunch Break
- Renewable Energy Resources (Tasks 2 & 6)
- Carbon Capture and Sequestration (Tasks 3 & 4)
- Economic Comparisons (Task 5)
- Recommendations and Conclusions

Please Ask Questions When You Have Them

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BLACK & VEATCH

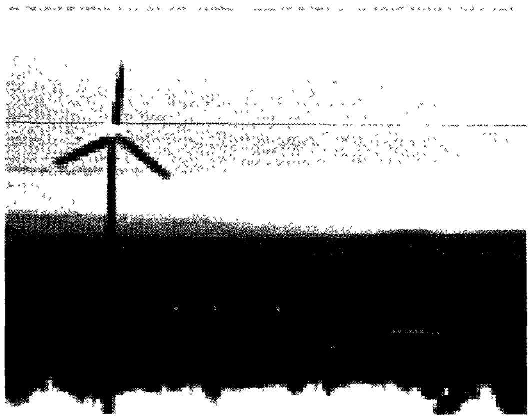
General Overview of Black & Veatch

Black & Veatch Corporation

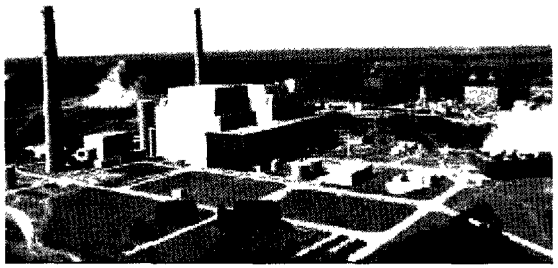
- Founded in 1915, headquarters in Kansas City
- A leading global engineering, consulting, and construction company
- Focus on infrastructure development in energy, water, information, and government markets
- Employee-owned company with more than 90 offices worldwide
- Over 9,000 Employees Worldwide
- Project Experience in Over 100 Countries on 6 Continents
- $3.2 Billion in Annual Revenues in 2007

B&V Energy offers a broad range of solutions for a global client base

Palmdale

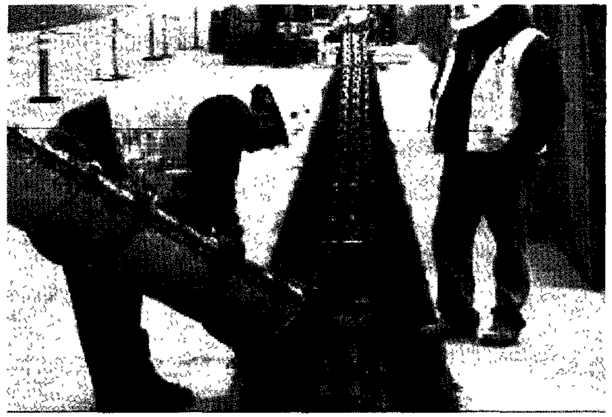


Weston

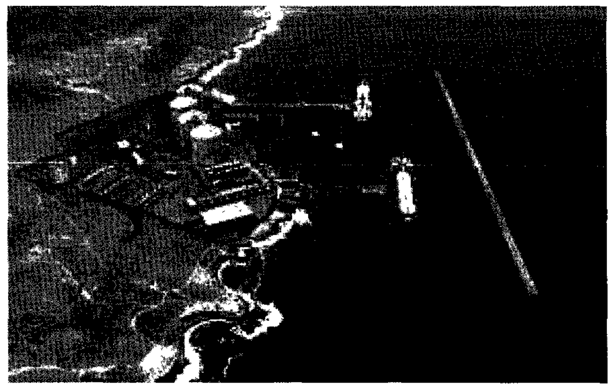


- Coal Plants
- Gas Turbines
- Combined Cycle
- Gasification / IGCC
- Nuclear
- Renewables
- AQCS
- Energy Services
- Power Delivery
- Substations
- Sulfur Recovery
- Natural Gas Processing
- LNG

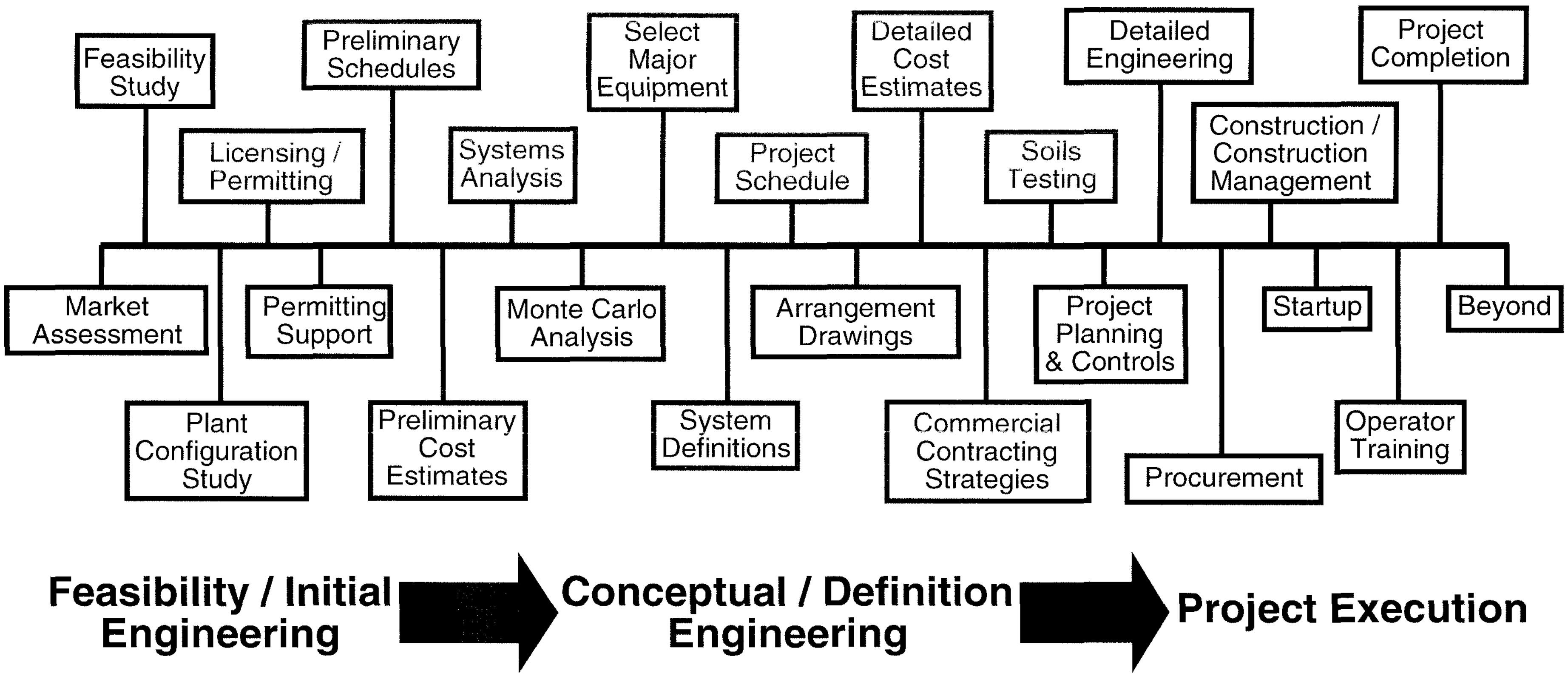
Jefferson-Martin



Costa Azul



We Understand the Entire Life Cycle of an Energy Project



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Presentation Take-aways

Key Results and Conclusions

- IPP is a Best-in-Class Facility
- GHG Emissions Trading Scheme (ETS) Not Fully Defined
- Significant Reductions of CO_2 from IPP Require Carbon Capture and Sequestration (CCS)
  - Large Scale Capture Ready 2012-2015
  - Large Scale Sequestration Ready 2015-2020
- Viable Projects Available Today to Lower GHG Footprint

Project Background

Project Scope

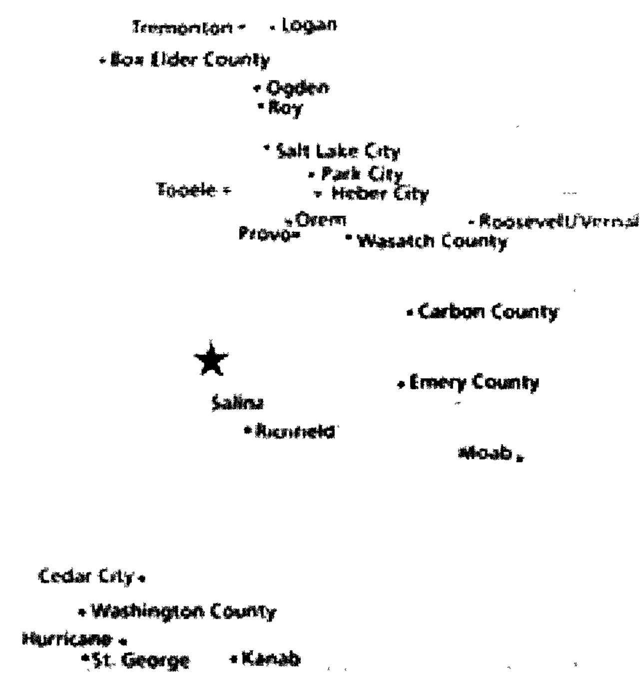
- Request from Intermountain Power Agency (IPA) and Southern California Public Power Authority (SCPPA)
- IPP GHG Reduction Feasibility Study
- Pre-Feasibility Level Study
- Work to begin in October 2007
- Final in April 2008

Purpose

Evaluate ways to reduce and/or capture CO_2 emissions from IPP coal fired Units 1 and 2. The ultimate goal, if achievable, is to reduce CO_2 emissions from Units 1 and 2 to meet California Energy Commission's (CEC) GHG Emission Performance Standard.

Intermountain Power Project

- Located near Delta, Utah
- Has two PC units with approximately 1,800 MW total capacity
- Engineered by Black & Veatch in the late 1980s
- Delivers power to 36 utilities in Utah and California
  - Most of the power is purchased by CA utilities



Tasks as Defined in the Contract

- Task 1. Improve Efficiencies
- Task 2. Alternative Fuels
- Task 3. Developing Technologies
- Task 4. CO_2 Capture and Sequestration
- Task 5. Carbon Trading
- Task 6. Renewable Resources

General Approach to Study

- Maintain Existing Net Output from IPP
  - Efficiency Improvements Only
  - Renewable Resources Displace Coal
  - Purchase Power for CO_2 Capture/Compression
- Estimate Levelized Cost of CO_2
- Provide Screening Level Only

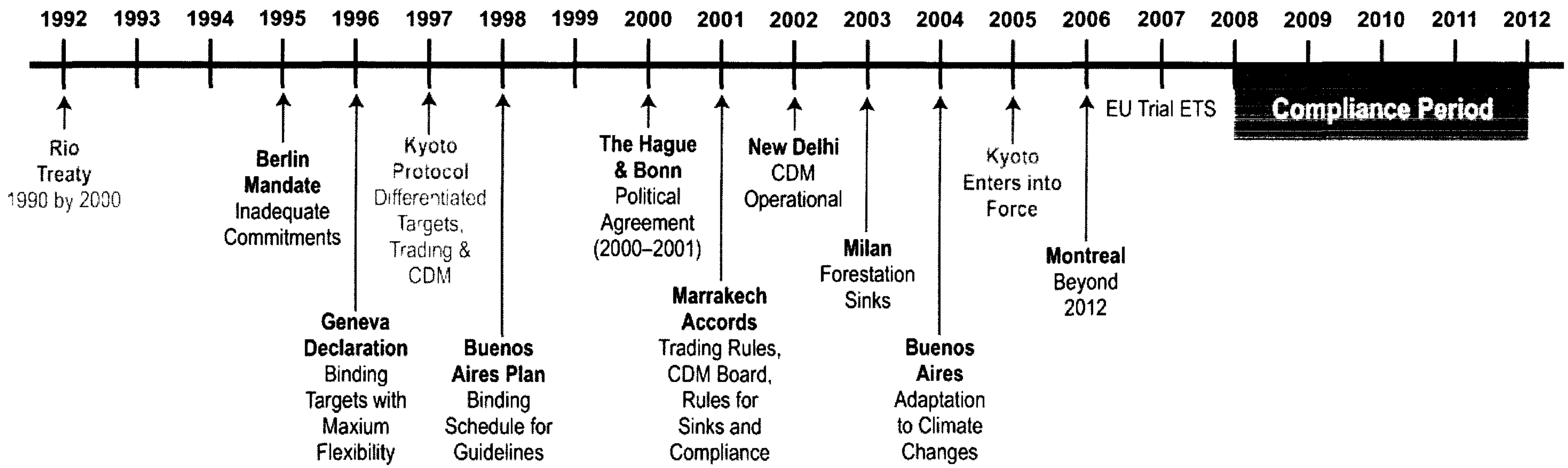
California GHG Reduction Policies

- **Executive Order S-3-05 signed June 1, 2005**
  - Sets statewide GHG reduction targets for 2010, 2020, and 2050
- **Global Warming Solutions Act of 2006 (AB 32)**
  - Enforceable limits beginning in 2012 to cap emissions at 1990 levels by 2020, compliance with market-based mechanisms
  - Must account for GHG emissions attributable to imported electricity consumed within the state
- **Senate Bill 1368 signed September 29, 2006**
  - CEC & California Public Utilities Commission (CPUC) establish 1,100 lbs/MWh GHG emission performance standard for new long-term power purchase agreements

Task 5
GHG Emissions Trading Programs

International, National, Regional, and State (California) Programs

"Kyoto Protocol"
(a.k.a. International GHG Reduction Treaty)



Developed (Annex I) countries to reduce emissions of six greenhouse gases 5.2% below 1990 levels by 2008 - 2012

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Kyoto Protocol Participation

- Signed and ratified
- Signed, ratification pending
- Signed, ratification declined
- No position

Flexibility Mechanisms

- Emissions Trading
- Joint Implementation
- Clean Development Mechanism

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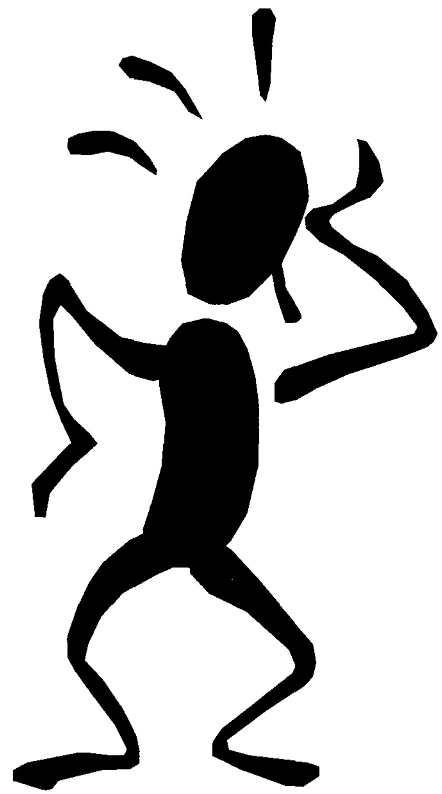
European Union ETS

- Collective commitment by 27 countries under Kyoto to achieve 8% reduction in GHG emissions from 1990 levels
- ETS to be implemented in three phases:
  - 2005-2008 – trial “warm-up” phase
  - 2008-2012 – Kyoto compliance phase
  - 2013 to 2020 – Post Kyoto commitment

European Union (EU) ETS: Lessons Learned in Phase I

- National Allocation Plans
  - Lack of accurate inventory of emissions
  - Overallocation of allowances
  - Inconsistencies in definition of "covered installation"
  - Allocations subject to political influence
- Result: Market failure CO_2 allowance prices declined from €30 to €0.1 per ton



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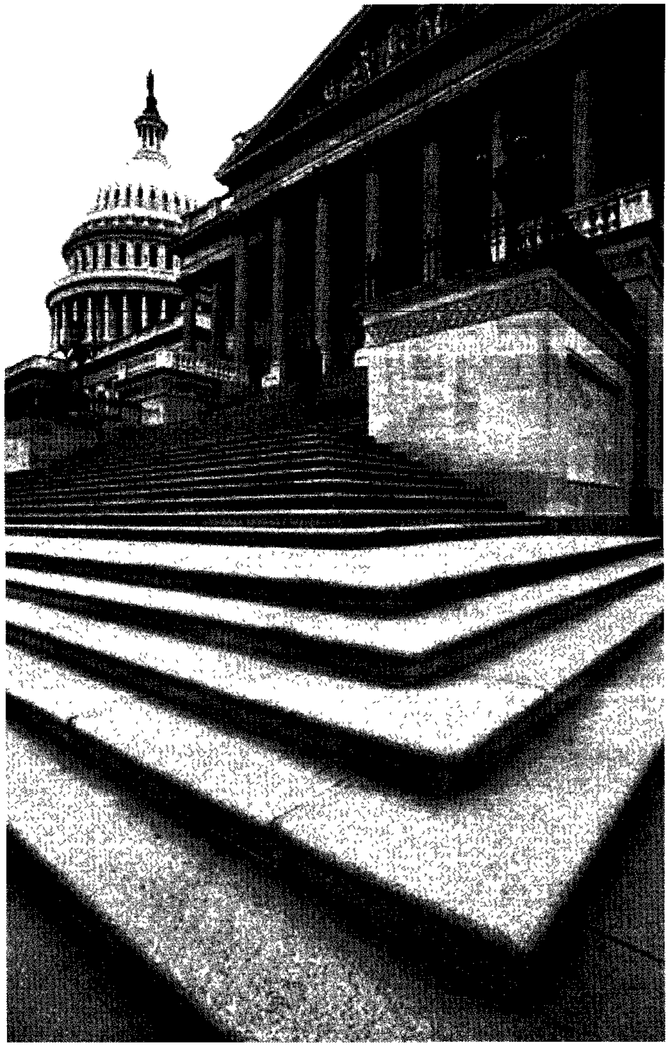
EU ETS Lessons Learned

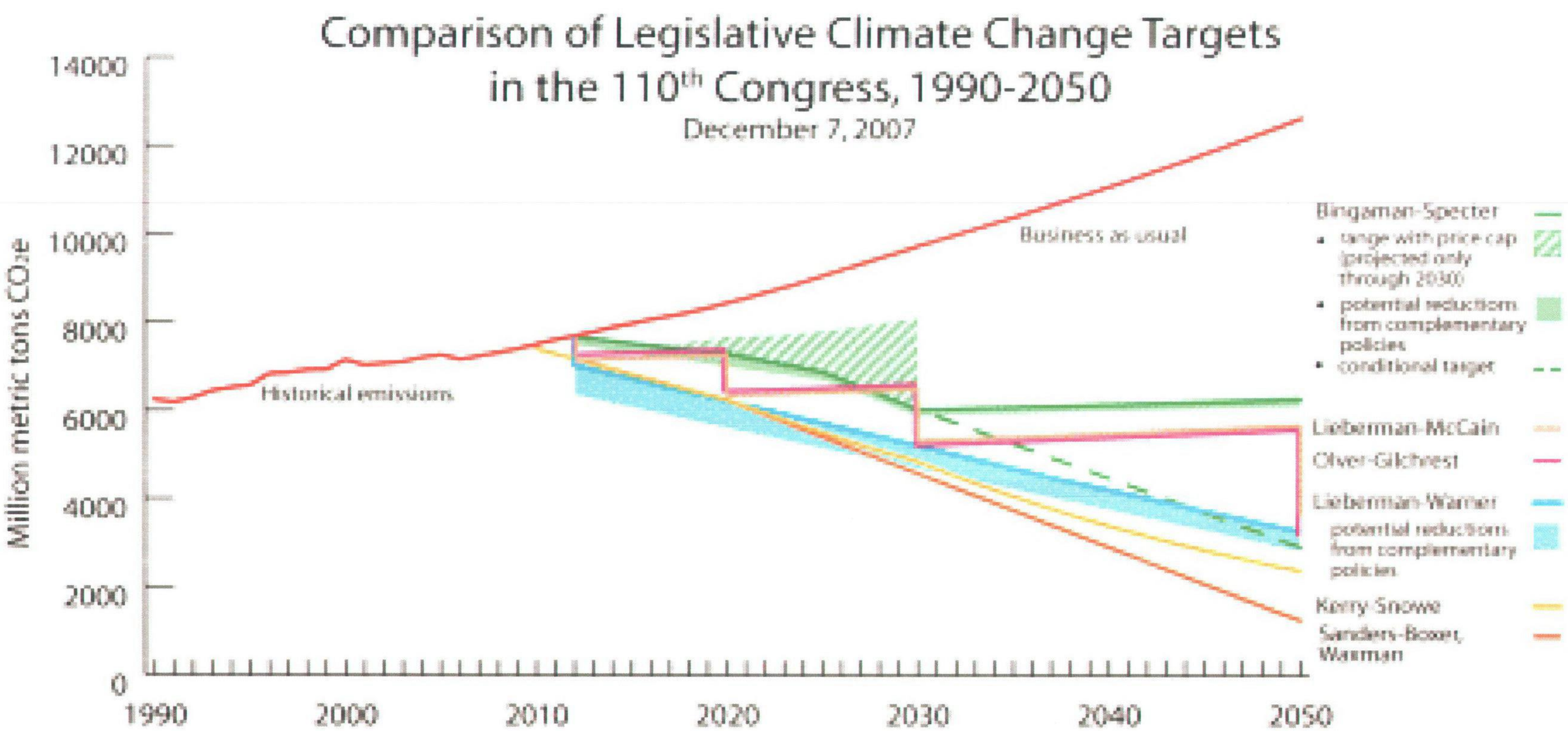
- Accuracy of emissions data
  - Accounting and monitoring
- Sufficient scarcity to force investments and trading
- Complexity and transparency of trading program
  - Minimization of political interference
- Time horizon for compliance
  - Banking/transition between phases
  - Early reductions and compliance planning

Federal GHG Legislation

- Multitude of proposed legislative bills seeking 60% - 90% reductions in GHG emissions over next three to four decades
- Key Issues/Differences
  - Carbon Tax vs. Market-Based Trading
  - Point of Regulation
  - Allocation vs. Auction of Allowances
  - Economy Safety Valve
  - Offsets
  - States Pre-emption
  - International Linkage and Developing Country Participation



Congressional GHG Bills



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For a full discussion of underlying methodology, assumptions and references, please see http://www.wri.org/usclimatetargets. WRI does not endorse any of these bills. This analysis is intended to fairly and accurately compare explicit carbon caps in Congressional climate proposals and uses underlying data that may differ from other analyses. Data post-2030 may be derived from extrapolation of EIA projections.

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Carbon Tax

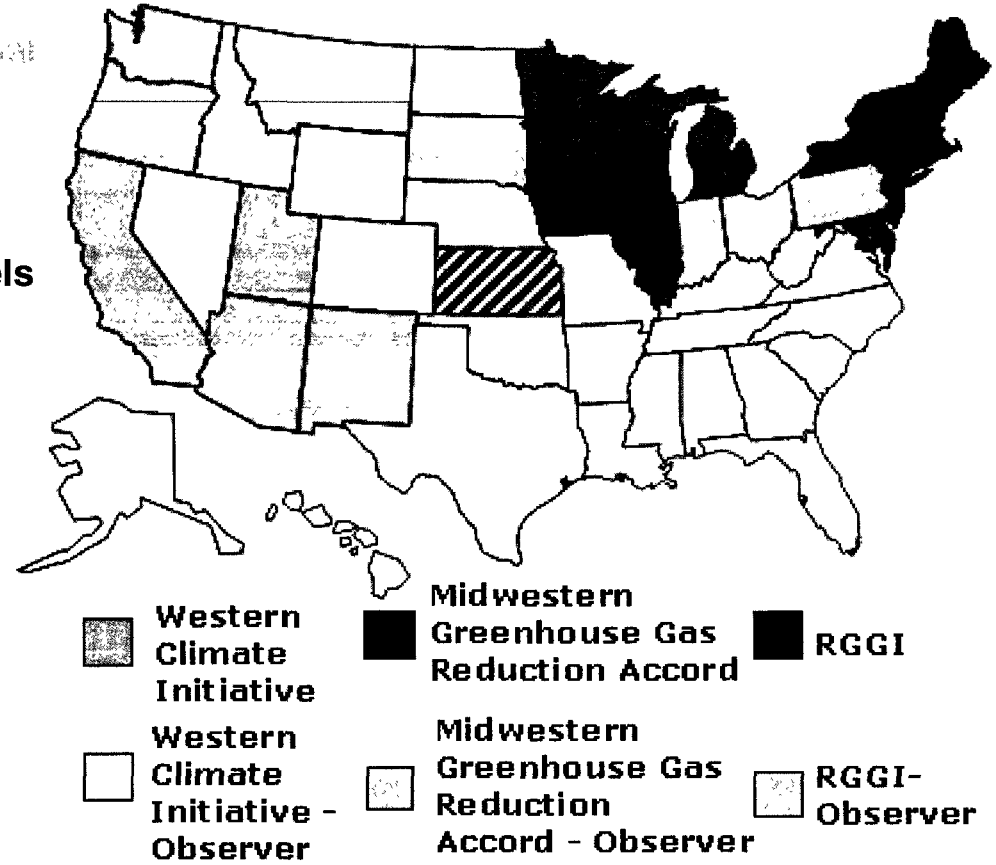
- Levy upstream on fuel's carbon content
  - Increased fuel costs pass along to increase costs of electricity and energy-intensive goods
  - Energy-saving behaviors encouraged, shift to lower carbon fuels
- Revenues used to reduce/replace other taxes (i.e., income)
- Price volatility risks and administrative burdens alleviated

Regional GHG Initiatives

Western Regional Climate Action Initiative economy-wide reductions 15% below 2005 levels by 2020

Midwest GHG Reduction Accord – multi-sector reduction target 60%-80% below current levels

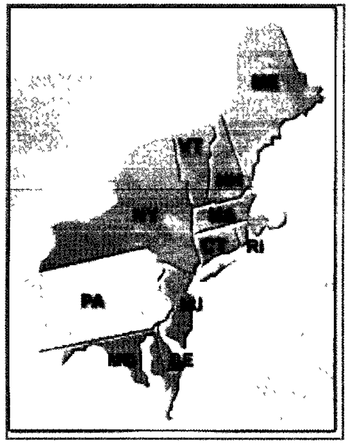
Regional GHG Initiative – caps power plant emissions in 2009, 10% reduction 2015-2019



Regional GHG Initiative

Initial Auctions 2008 — September 10, 2008 and December 17, 2008

Phase 1 2009 – 2014



Stabilize Power Sector Emissions

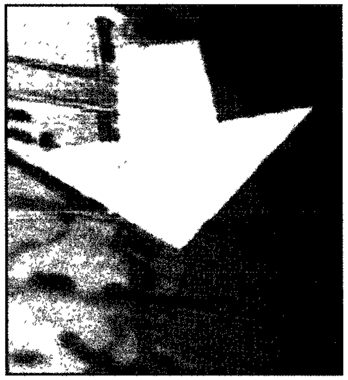
Fossil Fuel Generators of ≥ 25 MW

188 million ton CO_2 Regional Cap

State Allocation of Allowances

3 Year Compliance Period

Phase II 2015 - 2018



Reduce Power Sector Emissions

2.5% Annual Decline

2018 — **Annual Emissions Budget 10% Smaller than 2009**

Western Climate Initiative Timeline

January 2008 — Public Workshop to Identify Major Options

May 2008 — Present Recommendations on Key Elements

July 2008 — Present the Preferred Integrated Plan for Consideration

August 2008 — Design Regional Market-Based Multi-Sector Mechanism

Goal to Establish Economy-wide Program to Achieve Aggregate Emissions Reductions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 15 percent below 2005 levels by 2020

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California Global Warming Solutions Act

AB 32 Emissions Trading

AB32 Timeline

July 1, 2007 — **Early Action Measures for Implementation pre-2010 Adopted**

January 1, 2008 — **Mandatory GHG Emissions Reporting Adopted**

During 2009 — **Emission Reductions and Implementation**

January 1, 2009 – Plan to be adopted for how emissions reductions will be achieved

During 2009 – Language to implement plan drafted

During 2010 — **Early Action Measures Take Effect & Continued Rulemaking**

January 1, 2011 — **Completion of Major Rulemaking Activities**

January 1, 2012 — **GHG Rules & Market Mechanisms Take Effect**

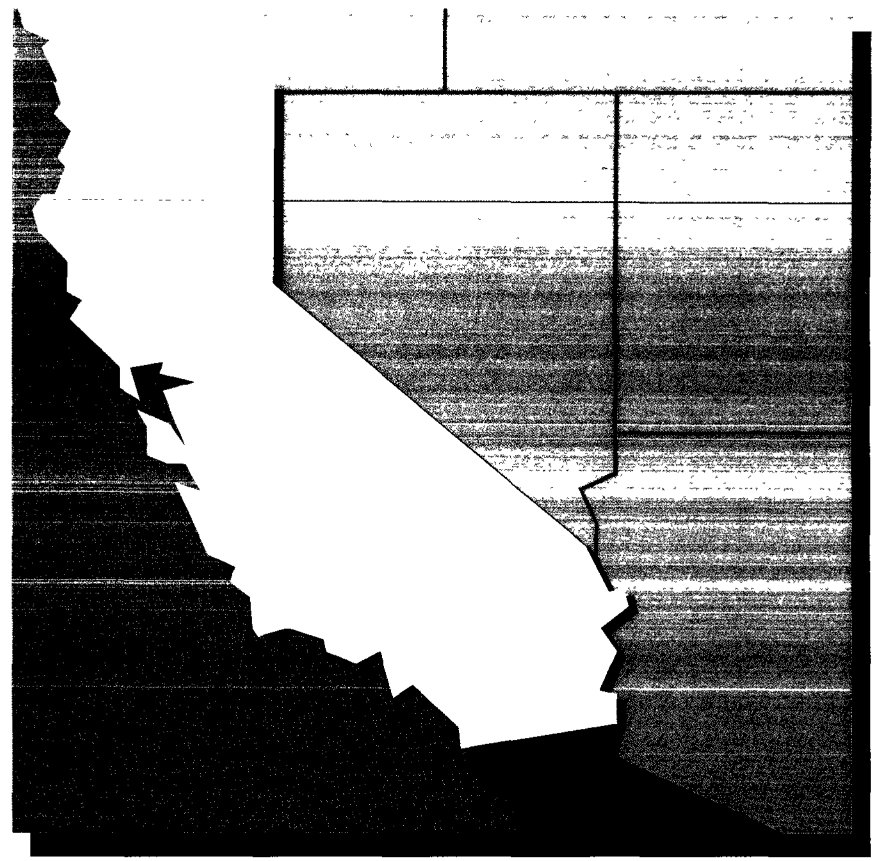
December 31, 2020 — **Deadline for Achieving 2020 GHG Emissions Cap**

Electricity Sector Point of Regulation

- Retail Providers
- Deliverer / First Seller
- In-State Generators
- Hybrid Retail/Generator

CA Trading Program - Elements and Considerations

- Distribution of Allowances
  - Allocation vs. Auction
  - Timing and Frequency
- New Entrants
- Safety Valve
- Offsets
- Early Actions



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CPUC/CEC Electricity Sector Recommendations

- Scope plan requirements at level of all cost-effective energy efficiency in the State
- Go beyond 20% renewable energy
- Move forward with multi-sector cap and trade system that includes electricity sector
  - Deliverers of electricity as point of regulation
  - Mix of allocation and auctioning of allowances

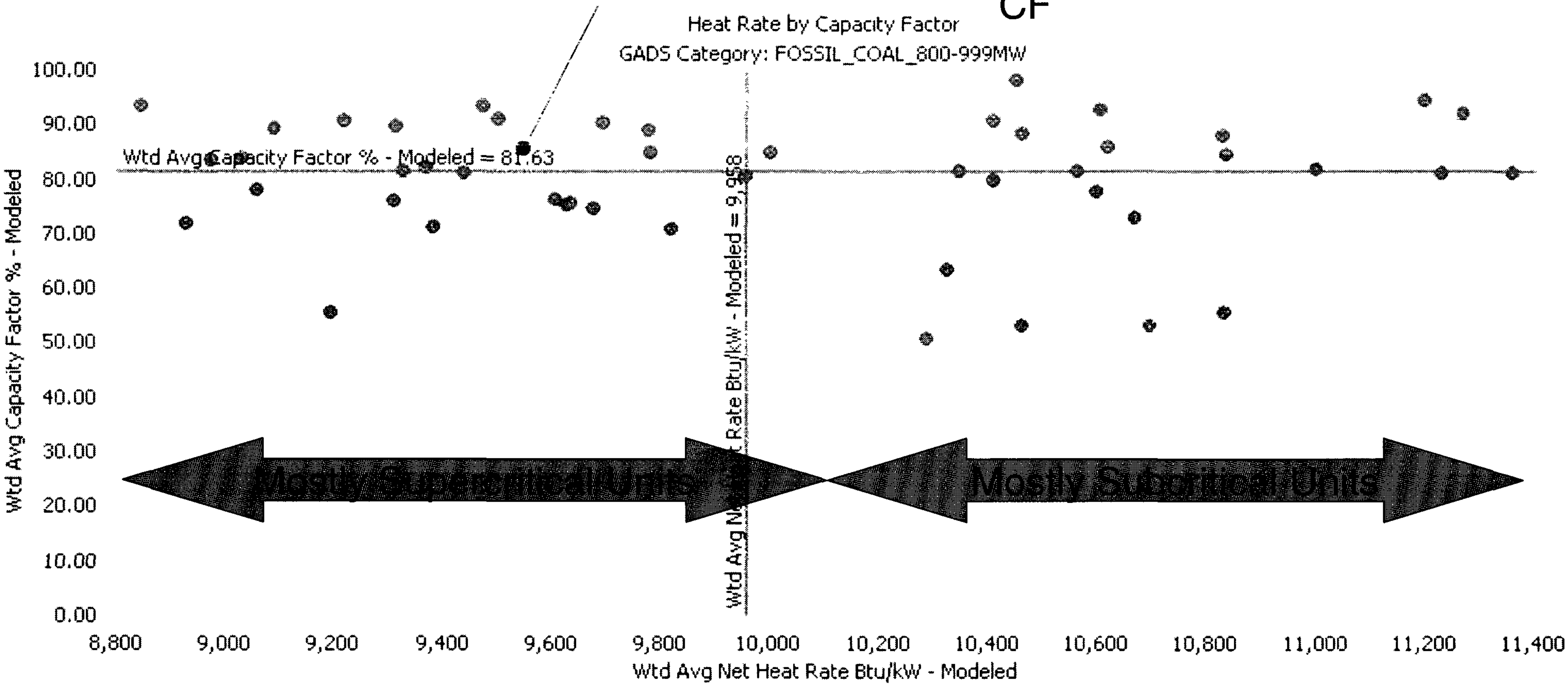
Task 1
IPP Efficiency Improvements

Approach to Task 1

- Design and Operating Data Collection
- 2 Day Site Visit; 32 Projects Identified
- 32 Projects Screened and Categorized
  - Capital Improvements
  - Maintenance Repair/Replace Strategies
  - Operations Support Systems
  - Operations Practices (not considered)
- Net Benefit Analysis of 18 Projects (@ $20 and $40 per ton)
- Project Report and Presentation

IPP – Limited Heat Rate Reduction Opportunity

IPP Units Average ~9,450 Btu/kWh at 85% CF



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Maximum CO_2 Reduction Opportunity (@ $40/ton)

- 32,000 ton/yr from Currently Planned Projects

+

- 142,000 ton/yr with a Capital Cost of $45.5M

=

- 172,000 ton/yr
- Rate reduced from 1,950 to 1,925 lb_m/MWh (1.3%)
- 3% of the way to the benchmark of 1,100 lb_m/MWh

Six Planned Projects

- 32,000 ton/yr from Currently Planned Projects

Project Description	**CO_2 Reduction (ton/yr)**
Closed Loop Combustion Optimization System	18,719
Cooling Tower Modifications (Further study required)	0
Replace Primary AH Baskets (Benefit incl in #21 PA Seals)	0
Generator Rewind	3,704
Compressed Air Audit & Repair/Replacement	5,141
Modify Pulverizers w/ Rotating throat and Static Classifiers	4,445
Total	32,008

Eight New Projects Viable @ $40/ton CO_2 Cost

- 142,000 ton/yr with a Capital Cost of $45.5M

Project Description	Est Capital Cost	CO_2 Reduction (ton/yr)	CO_2 Benefit ($/yr)	Heat Rate Reduction (Btu/kWh)	Heat Rate Benefit ($/yr)	Aux load benefit (MW)	Net Benefit ($/yr)	Breakeven Cost ($/ton$CO_2$)
Modification of PA Air Heater Sector Plates and Installation of Duplex Sealing System	$418,000	26,501	$1,060,036	6	$423,495	2.40	$1,457,575	$0
Upgrade IPT Steam Path	$13,333,000	41,597	$1,663,874	29	$664,735	0.00	$1,273,714	$0
Sliding Pressure Operation	$0	14,798	$591,922	10	$236,479	0.00	$832,580	$10
VFD Motor for Condensate Pumps	$1,312,000	7,734	$309,341	0	$123,585	1.04	$330,149	$0
Cycle Isolation Audit & Valve Repair/Replacement	$120,000	4,160	$166,387	3	$66,473	0.00	$224,435	$0
LP Turbine Upgrade One Hood	$27,000,000	40,706	$1,628,237	28	$650,497	0.00	$130,229	$29
Upgrade BFPT (Blades and Seals)	$2,000,000	4,245	$169,802	3	$67,838	0.00	$78,838	$22
High Efficiency Motor for Coal Pulverizers	$1,360,000	2,422	$96,891	0	$38,709	0.33	$27,484	$37
Summary Total *(Net Benefit >0 Only)*	**$45,543,000**	**142,162**	**$5,686,491**	**79**	**$2,271,811**	**3.8**	**$4,355,006**	

IP12_002462

Five New Projects Viable @ \$20/ton CO_2 Cost

- 95,000 ton/yr with a Capital Cost of \$15.2M

Project Description	Est Capital Cost	CO_2 Reduction (ton/yr)	CO_2 Benefit (\$/yr)	Heat Rate Reduction (Btu/kWh)	Heat Rate Benefit (\$/yr)	Aux load benefit (MW)	Net Benefit (\$/yr)	Breakeven Cost (\$/tonCO_2)
Modification of PA Air Heater Sector Plates and Installation of Duplex Sealing System	\$418,000	26,501	\$530,018	6	\$423,495	2.40	\$927,557	\$0
Upgrade IPT Steam Path	\$13,333,000	41,597	\$831,937	29	\$664,735	0.00	\$441,777	\$0
Sliding Pressure Operation	\$0	14,798	\$295,961	10	\$236,479	0.00	\$536,619	\$10
VFD Motor for Condensate Pumps	\$1,312,000	7,734	\$154,670	0	\$123,585	1.04	\$175,479	\$0
Cycle Isolation Audit & Valve Repair/Replacement	\$120,000	4,160	\$83,194	3	\$66,473	0.00	\$141,242	\$0
~~Upgrade BFPT (Blades and Seals)~~	~~\$2,000,000~~	~~4,245~~	~~\$84,901~~	~~3~~	~~\$67,838~~	~~0.00~~	-\$6,063	~~\$22~~
~~High Efficiency Motor for Coal Pulverizers~~	~~\$1,360,000~~	~~2,422~~	~~\$48,446~~	~~0~~	~~\$38,709~~	~~0.33~~	-\$20,961	~~\$37~~
~~LP Turbine Upgrade One Hood~~	~~\$27,000,000~~	~~40,706~~	~~\$814,119~~	~~28~~	~~\$650,497~~	~~0.00~~	-\$683,890	~~\$29~~
Summary Total *(Net Benefit >0 Only)*	**\$15,183,000**	**94,789**	**\$1,895,780**	**48**	**\$1,514,767**	**3.4**	**\$2,222,674**	

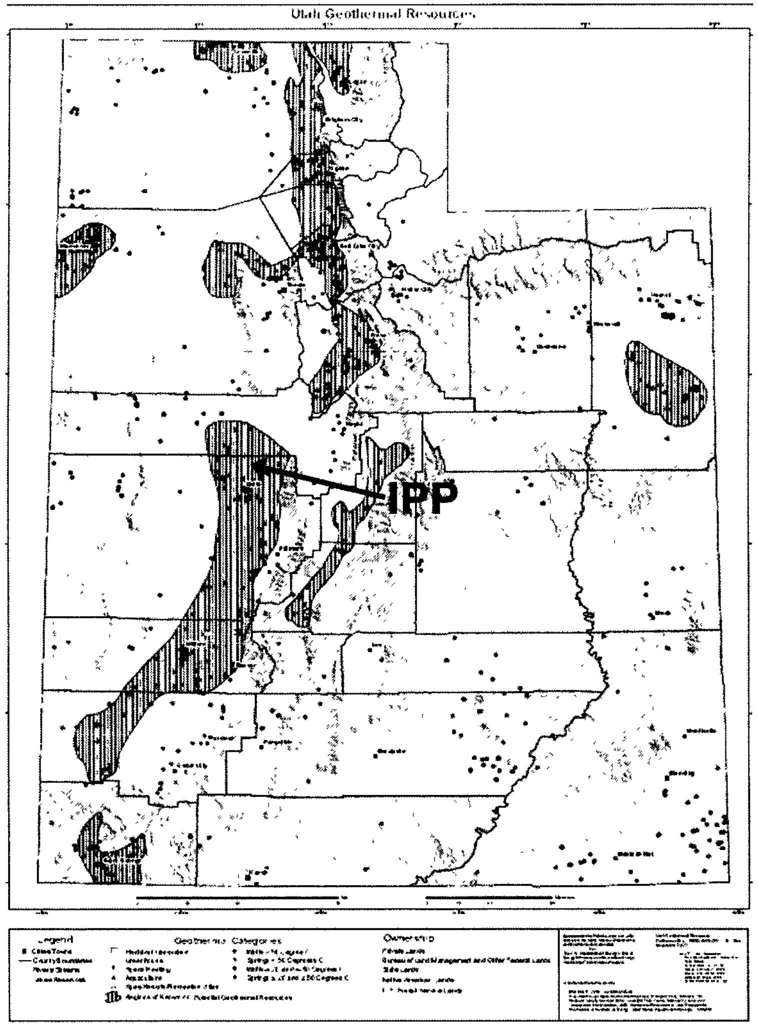
Tasks 2 and 6
Renewable Resources

Renewable Energy Options

- Geothermal feedwater heating
- Geothermal power
- Solar thermal feedwater heating
- Solar thermal power
- Wind
- Hydro
- Co-firing – both biomass and natural gas

Geothermal

- IPP lies in a promising geothermal area
- B&V analyzed the potential for
  - Geothermal feedwater heating
  - Stand-alone geothermal power generation



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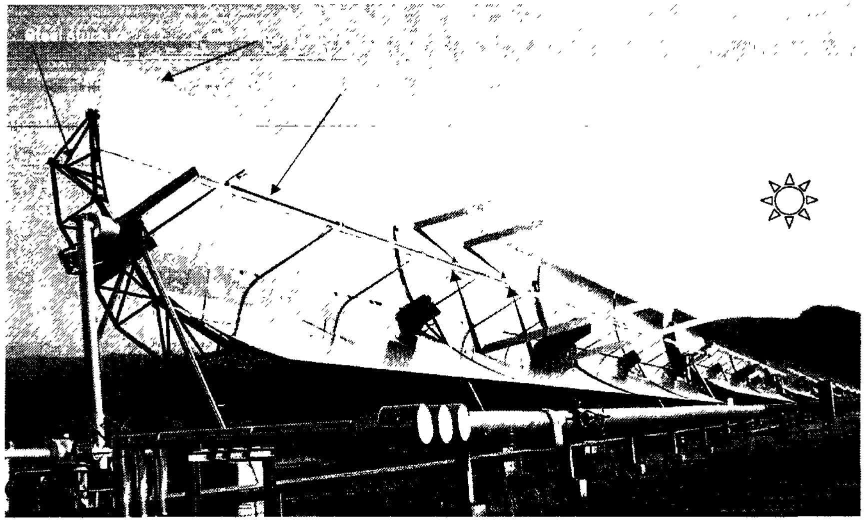
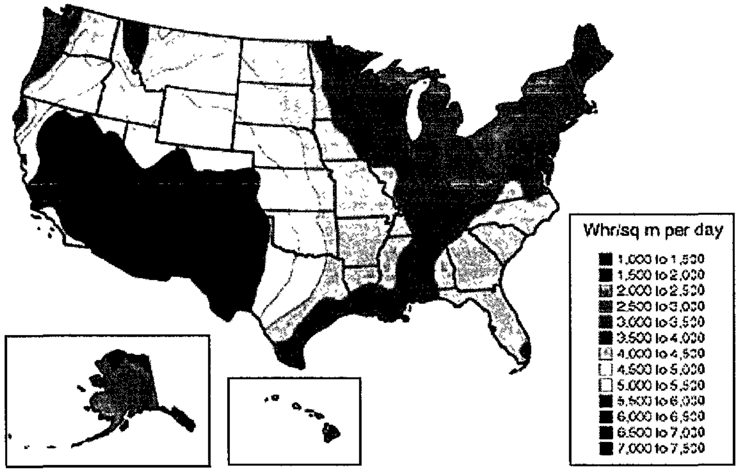
Geothermal

- Geothermal resource near IPP does not have sufficient temperature/flow rate to be thermodynamically feasible for feedwater heating
- One identified area is feasible for geothermal power production (binary cycle)
  - May already be under development by Raser Technologies

Solar



- B&V analyzed the potential for
    - Solar thermal feedwater heating
    - Stand-alone solar thermal power generation
- Assumed parabolic trough technology



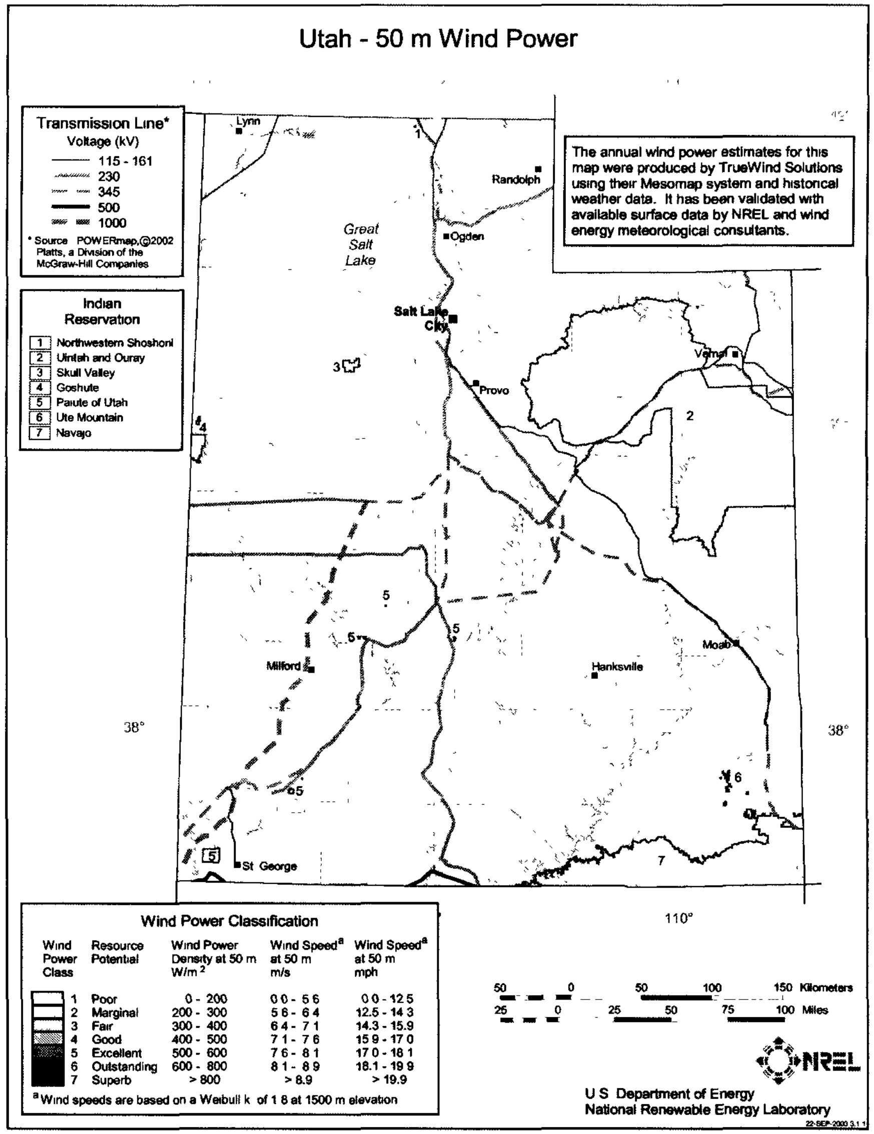
Solar resource for a concentrating collector

Solar

- Solar thermal feedwater heating
  - Hot working fluid heats feedwater, reducing extraction steam needed
  - Solar field would be located near IPP
- Solar thermal electric
  - Complete power block required
  - Solar fields located in area of flat terrain near transmission

Wind

- Limited wind resources around IPP, mostly along ridgelines
- Best opportunities near the IPP-Gonder transmission line towards Nevada
- Intermittent resource (CF ≈ 29%)



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Hydro

- Limited hydro opportunities
- Best potential site is the upper Sevier River
- Significant opposition to development would be expected

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Others

- Small potential for anaerobic digestion and landfill gas
  - AD potential for 5 to 8 MW
  - Further study needed to quantify cost and potential
  - Not known if methane reduction credits are eligible
- Minimal potential for landfill gas

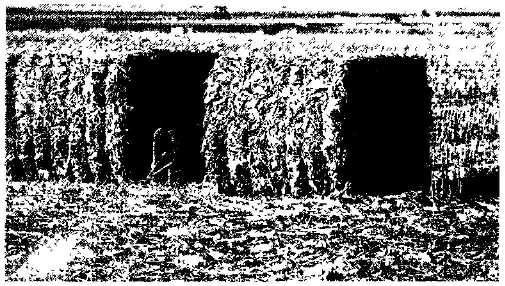
Summary

Renewable Energy Options Comparison.

Option	Near-Term Lev. Cost of CO_2 Reduction ($/ton)	Near-Term Potential CO_2 Reduction (ton/yr)	First Year Available	Near-Term Percent IPP CO_2 Reduction	Long-Term Percent IPP CO_2 Reduction
Geothermal Power	136	102,000 *(Capacity = 15 MW)*	2012	0.7%	0.7%
Solar Power	230	186,000 *(Capacity = 100 MW)*	2012	1.3%	13.0%
Solar Feedwater Heating	135	104,000 *(Capacity = 50 MW)*	2010	0.7%	1.5 to 3.0%
Wind	91	988,000 *(Capacity = 400 MW)*	2011	7.0%	21.2%
Hydro	111	64,000 *(Capacity = 15 MW)*	2013	0.5%	0.8%

Alternative Fuels

- Looked at four different co-firing options:
  - 1% (direct blend)
  - 10% (separate injection)
  - 20% (new burners installed)
  - 10% natural gas (new igniters installed)



Alternative Fuels

Alternative Fuel Quantities.

	Heat Input (MBtu/yr)*	Approximate Quantity
1% biomass	1,406,000	220,000 wet tons/yr
10% biomass	14,130,000	2,100,000 wet tons/yr
20% biomass	28,490,000	4,100,000 wet tons/yr
10% natural gas	14,160,000	13,800 million standard cubic feet (scf)/yr

* Based on average IPP generation from 2006 and 2007. Considers Net Plant Heat Rate reduction that occurs by co-firing alternative fuels with coal.

IP12_002475

Alternative Fuels

Co-Firing Options Comparison (With CO_2 Penalty).

	Levelized Cost of CO_2 Reduction ($/ton)		**Potential CO_2 Reduction (ton/yr)**		**Percent IPP CO_2 Reduction**	
	With CO_2Penalty	Without CO_2 Penalty	With CO_2Penalty	Without CO_2 Penalty	With CO_2Penalty	Without CO_2 Penalty
1% Biomass	41	35	124,000	146,000	0.9%	1.0%
10% Biomass	69	48	1,020,000	1,460,000	7.5%	10.0%
20% Biomass	80	48	1,750,000	2,900,000	12.0%	20.0%
10% Natural Gas	75	75	496,000	496,000	3.5%	3.5%

Note: Penalty accounts for the CO_2 emitted during the harvesting, processing, and transportation of biomass fuels, as required under CA Senate Bill 1368, section 8341.

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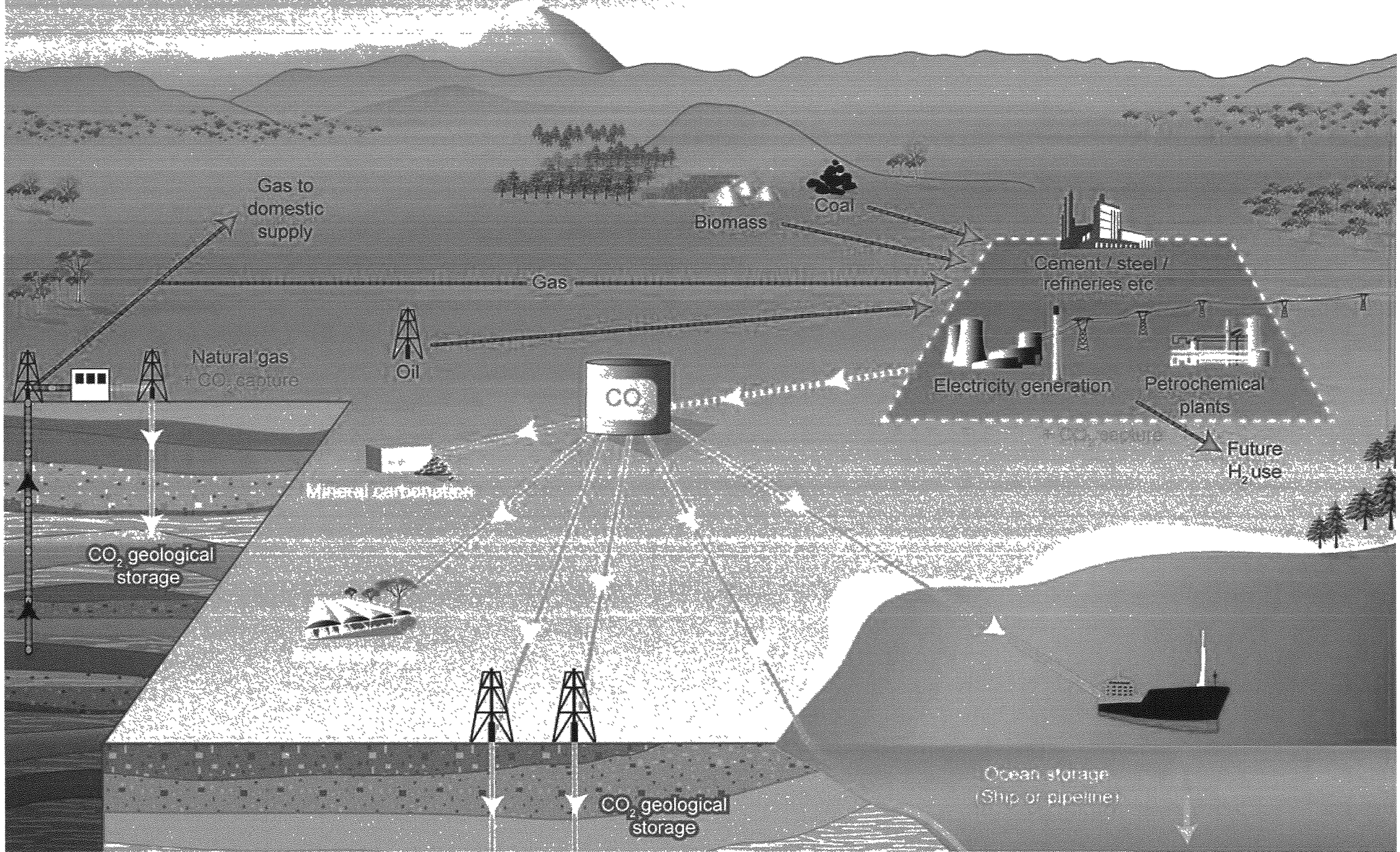
Tasks 3 and 4
Carbon Capture and Sequestration

Schematic diagram of possible CCS systems



Carbon Dioxide Capture and Storage Project Life Cycle Stages

CAPTURE

Pre- or Post- Combustion Exhaust Gas Removal and Compression

→

TRANSPORT

Delivery from Capture Source to Injection Well

→

INJECTION AND STORAGE

Subsurface Injection Storage and Long-Term Stewardship

Capture Project

Stationary Source Siting, Permitting and Operation

Transport Project

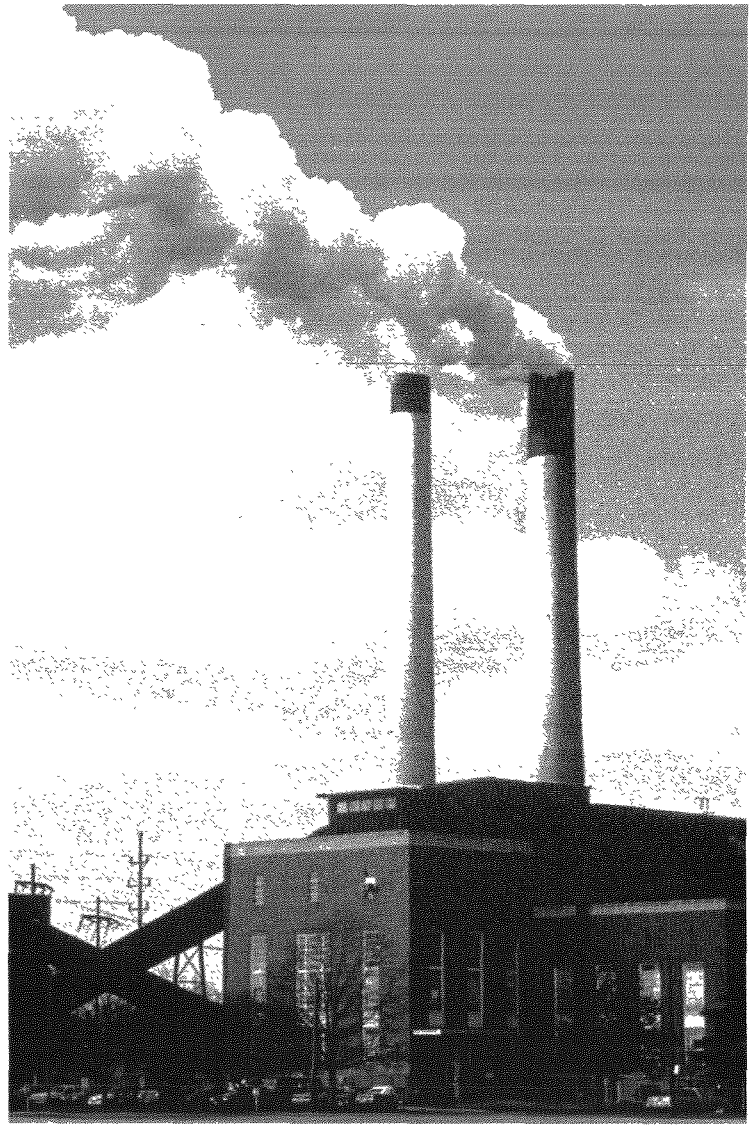
Pipeline Routing, Permitting and Operation

Injection and Storage Project

Site Characterization, Permitting, Operation and Closure

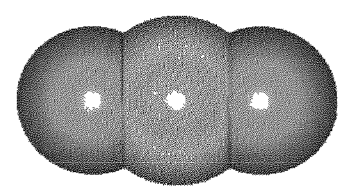
CO_2 Capture in Power Plants

- Available technologies exist for capturing CO_2 from fossil power plants
- Several unproven technologies show promise
- No US power plants currently capturing significant percentage (>15%) of CO_2 generated
- Costs to capture CO_2 are high for all processes



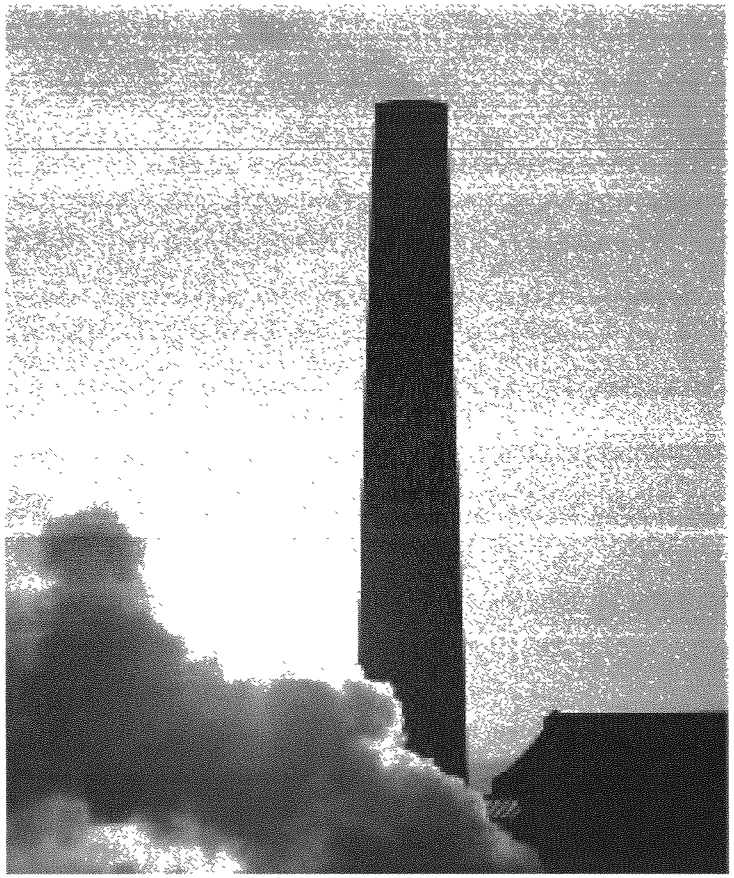
Three Categories of Capture Processes

- Post-Combustion Capture
  - Large volumes of flue gas and CO_2
  - Processes not proven at scale
- Pre-Combustion Capture
  - IGCC
- Oxy-Fuel Combustion
  - Not Considered Further

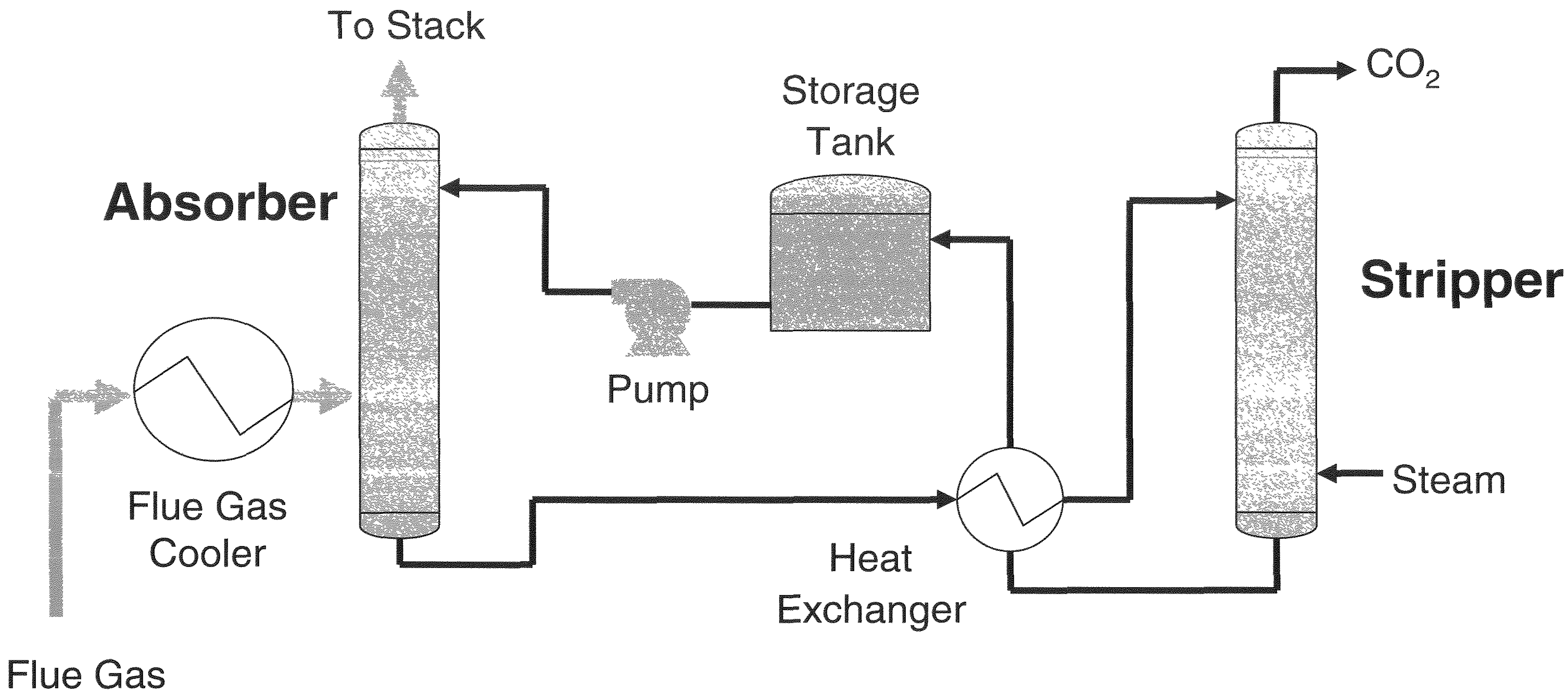


Post-Combustion Processes

- **Amine solvent**
  - Proven technology at smaller scale
  - Chemical solvent, typically monoethanolamine (MEA)
- **Ammonia solvent**
  - Similar configuration to amine



Simplified Post-Combustion Process



Chilled Ammonia Solution

NH_3

- Technology under development by Alstom and EPRI
- Similar to amine absorber/stripper, but operates at lower temperature
- Flue gas chilled to 32-50° F for high capture efficiency and low NH_3 emission
- Chilling flue gas also reduces volume and increases CO_2 concentration (due to H_2O removal)
- 1.7 MW pilot scale plant at We Energies Pleasant Prairie Station (2008 Operation)
- AEP and Alstom announced plans to install 10 MW pilot at Mountaineer Plant in W. Va.

Amine and Ammonia Performance Comparison

IPP Performance Estimate for CO_2 Capture.

	Amine	Ammonia
Flue Gas to CO_2 Capture, percent	68	70
CO_2 in Flue Gas from Power Plant, tons per hour (tph)	1,755	1,755
CO_2 Captured, tph	958	996
CO_2 Captured, percent	54.6	56.8
CO_2 to Atmosphere, tph	797	759
Net Power without CO_2 Capture, MW	1,800	1,800
Net Power from PC Units with CO_2 Capture, MW	1,460	1,387
CO_2 emitted, pounds per megawatt-hour (lb/MWh)	1,092	1,094
Additional Cooling Water Makeup from River, gallons per minute (gpm)	4,260	2,252

Amine and Ammonia Cost Comparison

Capital and Operating Costs (2008 US$).

	Amine	Ammonia
CCC Direct Capital Cost ($million)	1,400	1,300
CO_2 Transport Direct Cost ($million)	470	470
Total Direct Cost ($million)	1,870	1,770
Owner's Cost at 40% of Direct ($million)	748	708
Total Capital Cost ($million)	2,618	2,478
O&M Cost		
Fixed ($million/year)	2	2
Variable ($million/year)	29.2	37.5

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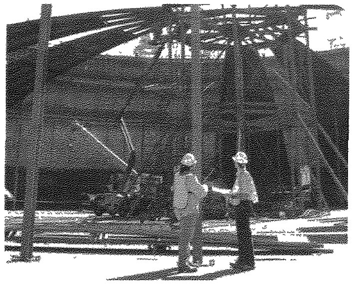




Risks and Liabilities

Key issues and challenges of CCS regulation

- Ecological and health safety risks
- Regulatory agencies' jurisdiction
- Classification of CO_2
- Ownership and property rights
- Long-term post-closure assurance
- Public acceptance

Human health and ecological risks

Health Risks

- No physiological effects up to 1% (10,000 ppm)
- 1 – 3% adaptation
- 3 – 5% respiratory rate and discomfort
- > 5% impairment of physical and mental abilities, loss of consciousness
- > 10% rapid loss of consciousness, coma, death

Ecological Risks

- Plants more tolerant than animals
- Minimal impacts from small scale, short-term gas leaks
- Persistent leaks could suppress respiration in root zone, result in soil acidification, lower pH in aquatic ecosystems
- Catastrophic releases (20-30%) can kill vegetation and animals

Regulatory agencies' jurisdictions

Different federal, state, and local agencies responsible for ensuring materials are captured, handled, transported, injected, and stored in a safe and appropriate manner

Federal Agencies

- Environmental Protection Agency
- DOT Office of Pipeline Safety
- Minerals Management Service
- Occupational Safety and Health Administration

State Agencies

- Public Utility and Oil & Gas Commissions
- Environmental & Natural Resource Agency
- Department of Transportation

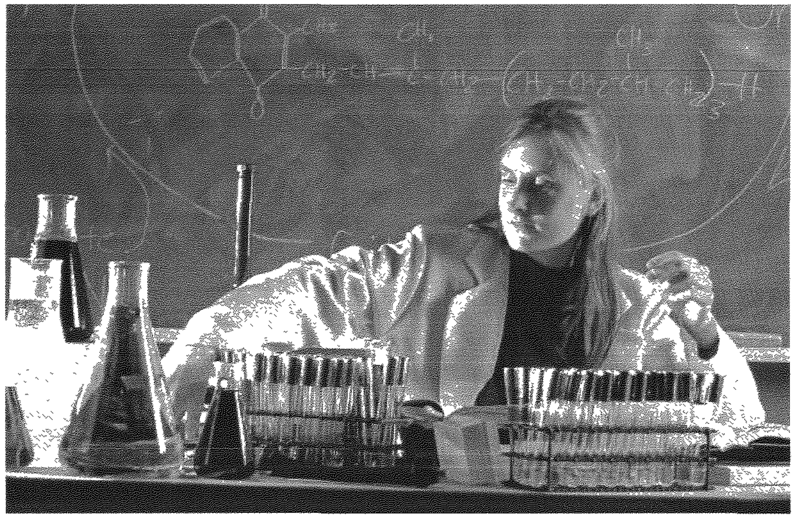
Local Authorities

- Planning & Zoning

Key issues and challenges

Classification of CO_2

- Commodity
- Pollutant
- Waste
- Hazardous / Dangerous
- Non-hazardous



Key Issues & Challenges

Ownership and Property Rights

- Surface
  - Access
  - Easements
- Subsurface
  - Minerals
  - Formations
  - Pore space

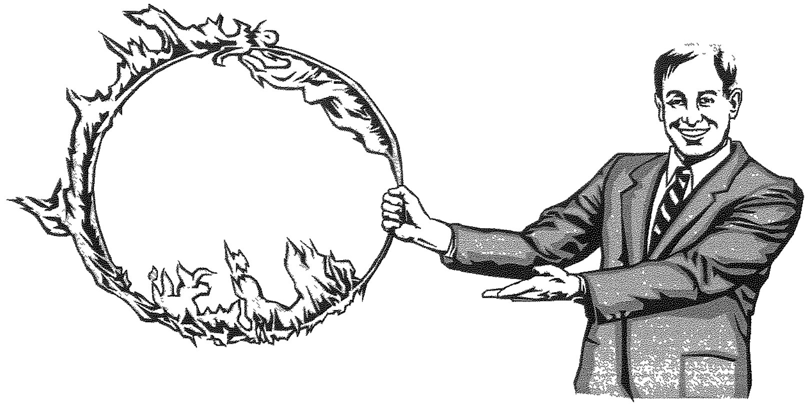
- Personal property
  - CO_2
  - Credits
- Legal Doctrines
  - Capture
  - Eminent Domain
  - Injuries and Damages

Long-term post-closure assurance

- Intergenerational regulation
- Transfer long-term risk liability to government / public
- Responsibility for orphaned sites
- Monitoring for migration and leakage
- Accidental release liability and remediation
- Global risks of leakage and releases
- Longevity of institutions and transfer of knowledge

Public acceptance

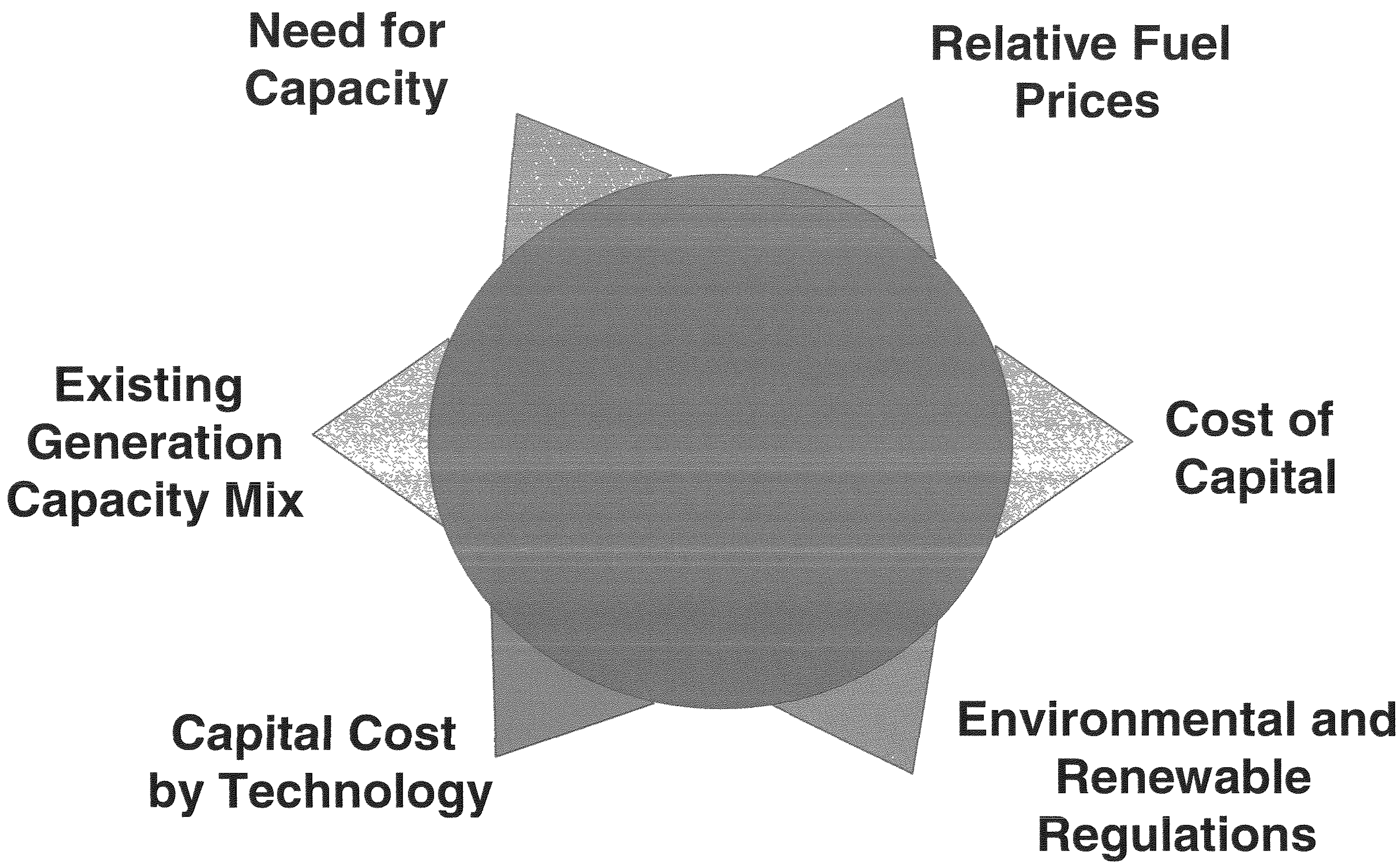
- Demonstration and confidence in geologic sequestration
- NIMBY / NUMBY issues:
  - Decrease in property values
  - Environmental justice
  - Accidents and safety hazards
- Level and role of public and NGO participation in siting and permitting
- Continued acceptance of costs and risks over time



Task 5
Economic Impacts of CO_2 Cap and Trade Programs

Lieberman-Warner
Western Climate Initiative
AB 32

Key drivers for baseline generation additions



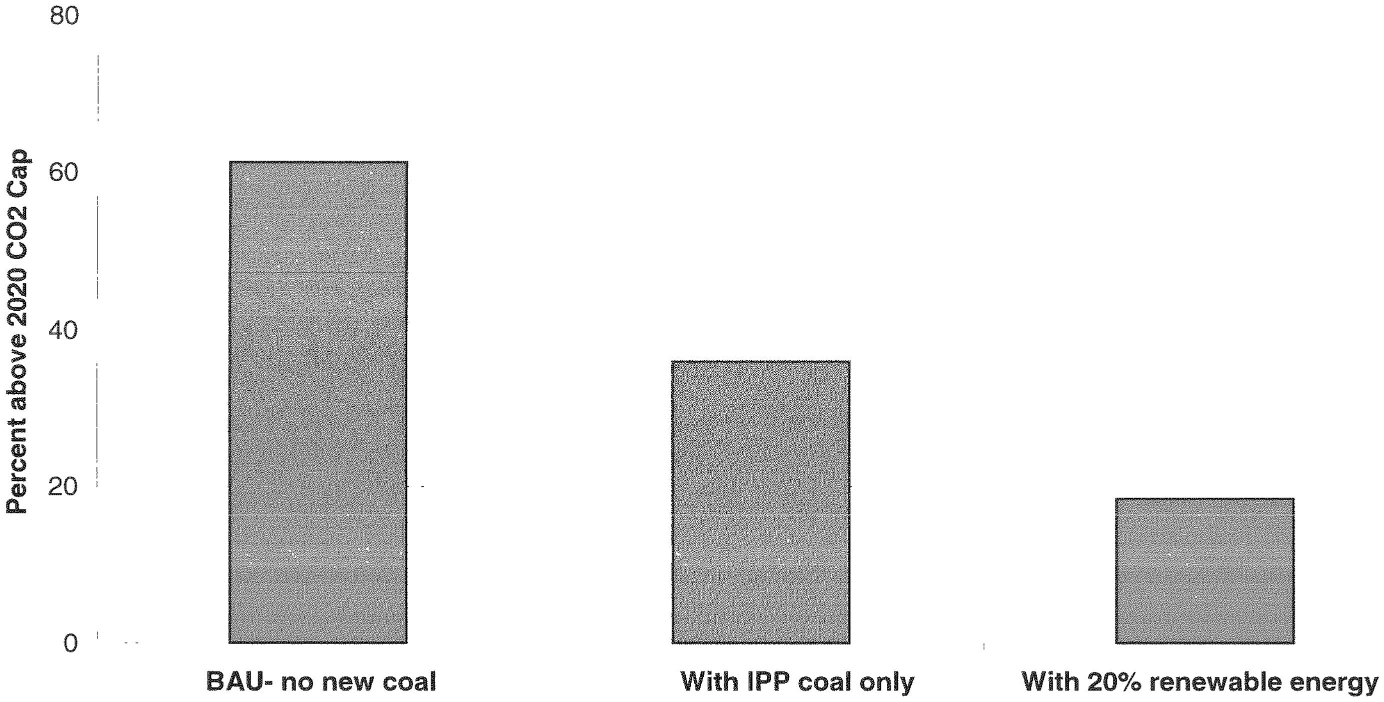
IPP May Control CO_2 or Purchase Allowances

- Economically, IPP should control emissions only to the point where the incremental cost of CO_2 control reaches the price of CO_2 allowances
- The price of allowances in a cap and trade program should be based on the cost of control by the last generator that makes the region meet its cap *– markets induce marginal cost-based pricing*
- Cap and trade induces use of least-cost CO_2 control measures first
- The price of allowances is a direct function of the cap level and the cost of control for all the generators in the trading area

CO_2 avoidance / abatement alternatives

- New combined cycle capacity in place of new coal capacity
- New combined cycle capacity coupled with wind generation in place of new coal capacity
- New nuclear capacity in place of new coal capacity
- IGCC capacity with capture and sequestration in place of new coal capacity
- New combined cycle capacity to replace existing inefficient coal generation
- Combined cycle capacity dispatches ahead of existing coal capacity reducing coal capacity factors
- Post-combustion control of existing PC capacity
- IGCC with capture in place of new combined cycle capacity

CA – What abatement measures will be needed?



BAU – Business as usual with 11% renewables

Assuming all current domestic and imported coal except for IPP is replaced by gas generation, and renewable generation is increased to 20%, results in CO_2 emissions 19% above the AB 32 cap proposed for 2020.

IP12_002499

Implications for IPP

- If AB 32 remains the only program applicable to IPP, it may want to consider taking actions that cost less than approximately $40 per ton to remove CO_2
- Implementation of the WCI may reduce the price of CO_2 allowances but only slightly
- If the Lieberman-Warner bill is enacted with currently proposed caps, the price of CO_2 allowances is likely to cause IPP to consider adding carbon capture and sequestration
- In all cases, there will likely be pressure to increasingly cycle IPP as combined cycle generators start dispatching ahead of it due to the cost of CO_2

Summary

Comparison of Levelized Cost of CO_2

	Scenario	Capital Cost ($1000)	Operating Cost ($1000/yr)	CO2 Reduction (tons/year)	Levelized Cost of CO2 ($/ton CO2)
1	Modification of PA Air Heater and Seals	418	-	26,501	0
1	Sliding Pressure Operation	0	-	14,798	0
1	VFD Motor for Condensate Pumps	1,312	-	7,734	0
1	Cycle Isolation Audit and Valve Repair/Replacement	120	-	4,160	0
1	Upgrade IPT Steam Path	13,333	-	41,597	10
1	Upgrade BFPT (Blades and Seals)	2,000	-	4,245	22
1	"High Efficiency Motor for Coal Pulverizers"	1,360	-	2,422	29
1	LP Turbine Upgrade One Hood	27,000	-	40,706	37
2	1 Percent Biomass	1,206	1,100	124,000	41
4	Amine CO2 Scrubbing	2,619,000	31,200	7,972,000	59
4	Ammonia CO2 Scrubbing	2,479,000	37,500	8,289,000	63
2	10 Percent Biomass	314,280	1,300	1,020,000	69
2	10 Percent Natural Gas	17,640	1,100	496,000	75
2	20 Percent Biomass	549,720	1,610	1,750,000	80
6	Wind	800,000	20,700	988,000	91
6	Hydro	42,520	550	64,000	111
6	Solar Feedwater Heating	135,000	2,900	104,000	135
6	Geothermal Power	76,500	6,100	102,000	136
6	Solar Power	420,000	5,800	186,000	230

Key Results and Conclusions

- IPP is a Best-in-Class Facility
- GHG ETS Not Fully Defined
- Significant Reductions of CO_2 from IPP Require CCS
  - Large Scale Capture Ready 2012-2015
  - Large Scale Sequestration Ready 2015-2020
- Viable Projects Available Today to Lower GHG Footprint

Conclusions

- Some efficiency improvements appear to be viable regardless of CO_2 reduction requirements
- Efficiency improvements do not have a significant impact on CO_2 emissions
- Only CCS and/or carbon trading have the capability to reach the target of 1,100 lb/MWh
- Carbon trading programs with CO_2 costs at <~$60/ton will provide a better option than CCS
- ***SCREENING LEVEL ANALYSIS ONLY***